Chapter 6 : Lifecycle Impacts on Fossil Energy and Greenhouse Gases

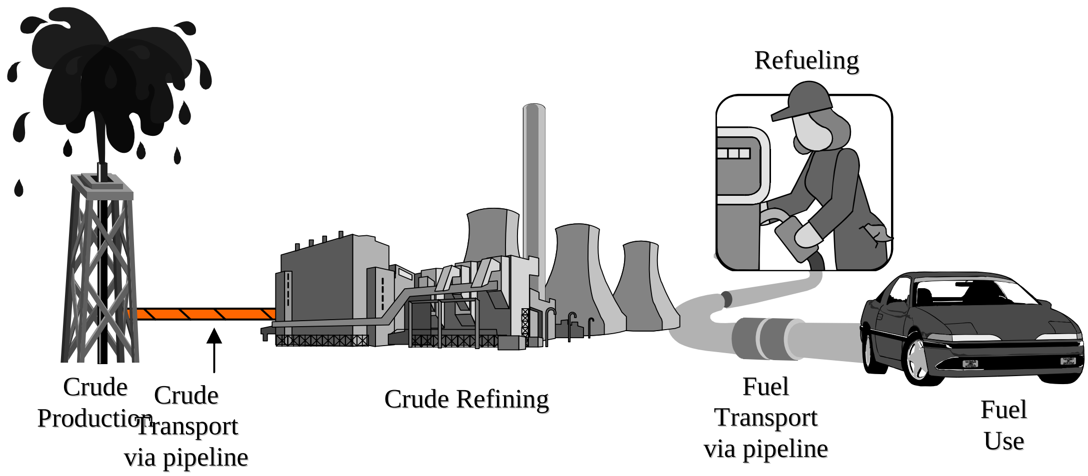
6.1 Lifecycle Modeling

Lifecycle modeling accounts for the energy and emissions from a production process. It incorporates the material aspects, input and output, of each step in a product system. This method helps to identify key processes and emission sources and facilitates comparisons between processes, consumption of natural resources, pollutant generation and environmental burden. It is important to note that lifecycle modeling typically provides only general comparisons, based on industry-wide estimates and assumptions; it does not reflect general equilibrium impacts, such as effects on input markets. The results of this type of analysis are highly dependent upon the input data used, the variables considered, and the assumptions made. Nevertheless, within these limitations, it can be an extremely useful tool for evaluating some of the environmental impacts of products and processes.

For transportation fuels, lifecycle modeling considers all steps in the production of the fuel. This includes production of the fuel feedstock, transportation of the fuel feedstock to a processing facility, fuel processing, and distribution of the fuel to the retail outlet. If the analysis considers only the finished product, it is sometimes called a 'well-to-pump' analysis; if the fuel combustion emissions are included, it can be called a 'well-to-wheel' analysis. While both approaches have advantages, in this work we have considered 'well-to-wheel' impacts. However, we are not addressing the issues of vehicle technology and energy efficiency, since we are making the assumption that the vehicle issues will not be affected by the presence of renewable fuels (i.e., efficiency of combusting one Btu of renewable fuel is equal to the efficiency of combusting one Btu of conventional fuel).

To put this type of analysis into perspective, consider the example of gasoline. The fuel feedstock is crude oil. The lifecycle analysis accounts for the energy used to extract the oil from the ground and any associated emissions, such as the natural gas that is flared at the well head. Next you evaluate transportation of the crude oil to the refinery. If it is domestic crude oil, it may be delivered by pipeline and/or barge. The analysis takes into account national trends for domestic oil transportation, and apportions energy used and emissions generated to each type of transportation. For foreign crude oil, the energy and emissions from ocean tankers is included, with an estimate of the average distance traveled by these tankers. Next is an estimation of the energy use and emissions from the refinery. Because gasoline is not the only product produced at the refinery, only a portion of the energy and emissions is allocated to gasoline production. There are different methods for making this allocation, based on the value of the co-products or an engineering assessment of the energy use and emissions from the various units in the refinery. You then evaluate the energy use and emissions from transporting the gasoline to market, via pipeline and truck, based on national average distances. Finally, vehicle energy use and emissions are estimated. Figure 6.1-1 illustrates this process.

Figure 6.1-1: Lifecycle Production Process, 'Well-to-Wheel', for Gasoline



Lifecycle modeling has been a useful tool in evaluating the environmental benefits of various alternative transportation fuels. It allows the replacement fuel to be fairly compared against the conventional transportation fuels – gasoline and diesel fuel. There have been several significant lifecycle analyses of transportation fuels done in the last decade. The lifecycle analysis done for this Renewable Fuel Standard (RFS) program uses a model developed by the Department of Energy (DOE) Argonne National Laboratory (ANL) called the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model. EPA has reviewed and modified GREET somewhat to reflect the data and assumptions appropriate for the RFS. These modifications are discussed further in section 6.1.2.

6.1.1 Scope of the Lifecycle Analysis

An important step in conducting a lifecycle analysis is to define the scope of the study. Varying results can be obtained depending on the scope identified. The scope of the analysis includes (1) the goal (2) the system boundaries (3) what flows are considered (4) temporal considerations and (5) modeling tools used. Each of these components is examined in the following sections.

6.1.1.1 Goal

The goal of this analysis is to determine the GHG emission and fossil fuel impact of the increased use of renewable fuels. This analysis is based on comparing future scenarios representing an increased percentage of the overall transportation sector fuel pool coming from renewable fuels compared to a reference case with the percentage of renewable fuels use at current levels. This implies that our future scenarios assume renewable fuels are displacing their petroleum based counterparts and causing less to be used. This RIA reflects increases in ethanol production of 85% and 150% respectively from the baseline. As this analysis is compared to a reference case we are only interested in the savings of the new or marginal renewable fuels used.

We have evaluated the absolute savings (e.g., tons of GHG emissions) as well as determining what percentage these absolute savings are in terms of overall transportation sector and economy wide emissions and energy use.

6.1.1.2 System Boundaries

The lifecycle analysis for the relevant activities identified in the GREET model is conducted without any regard to the geographic attributes of where emissions or energy use occurs. While the primary emphasis of a rulemaking analysis is typically to examine the domestic implications of a rulemaking, the lifecycle analysis of this final rule represent global reductions in GHG emissions and energy use, not just those occurring in the U.S. For example, under a full lifecycle assessment approach, the savings associated with reducing overseas crude oil extraction and refining are included here, as are the international emissions associated with producing imported ethanol. This assumes that for every gallon of gasoline that's not imported into the US, the corresponding quantity of crude oil is not extracted or processed to make this gasoline regardless where the extraction or production takes place. This type of modeling does not allow for behavioral changes that may be occur, called "rebounding effect," discussed later.

There are two important caveats to this analysis, both dealing with secondary impacts that may result internationally due to the expanded use of renewable fuels within the United States. The first caveat is the emissions associated with international land use change. Due to decreasing corn exports some changes to international land use may occur, for example, as more crops are planted in other regions to compensate for the decrease in crop exports from the U.S. While the emissions associated with domestic land use change are well understood and are included in our lifecycle analysis, we did not include the potential impact on international land use and any emissions that might directly result. Our currently modeling capability does not allow us to assess what international land use changes would occur or how these changes would affect greenhouse gas emissions. For example, we would need to know how international cropping patterns would change as well as farming inputs and practices that might affect emissions assessment. The second caveat results from the assumption of reduced petroleum imports. It is commonly presumed in economic analyses that demand for a normal good (i.e., oil) will increase as price decreases. A world wide reduction of oil price that could result from reduced U.S. imports can reduce the cost of producing transportation fuel which in turn would tend to reduce the price consumers would have to pay for this fuel. To the extent fuel prices are decreased, demand and consumption would tend to increase; this impact of reduced cost of driving is sometimes referred to as a "rebound effect." Such a greater consumption would presumably result in an increase in greenhouse gas emissions as consumers would drive more. These increased emissions would in part offset the emission benefits otherwise accounted for this rule[A]. It is important to note that GREET does not model behavioral changes that may affect prices of relevant commodities and goods which through various feedback loops ultimately energy use. The model does not include a general equilibrium approach that examines how a shock (whether economic, technical or legal) affects not only the sector of interest but also other sectors and the economy as a whole.[B] While such impacts of U.S. actions are important to

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[A] The extent to which this offset would occur would depend on sensitivity of demand to price.

[B] Since GREET is not a behavioral model, it cannot assess any economic efficiency implications associated with increased ethanol production. Analyzing these implications would be important for future ethanol rulemakings.

understand, we have not have fully considered and quantified the rebound effects of this renewable fuel standard. Nevertheless, such impacts remain an important consideration for future analysis.

The system boundaries for this study encompass both the renewable fuels lifecycle stages as well as their petroleum based counterparts. Table 6.1-1 shows the lifecycle stages considered for each fuel.

Table 6.1-1. Lifecycle Stages Included in Analysis

Corn Ethanol	Cellulosic Ethanol	Biodiesel	Petroleum-Based Gasoline	Petroleum-Based Diesel Fuel
Corn Farming	Biomass Farming	Soybean Farming	Crude Oil Extraction	Crude Oil Extraction
Corn Transport	Biomass Transport	Soybean Transport	Crude Oil Transport	Crude Oil Transport
		Soybean Crushing		
Ethanol Production	Ethanol Production	Biodiesel Production	Refining	Refining
Ethanol T&D	Ethanol T&D	Biodiesel T&D	Gasoline T&D	Diesel Fuel T&D
Ethanol Tailpipe Emissions	Ethanol Tailpipe Emissions	Biodiesel Tailpipe Emissions	Gasoline Tailpipe Emissions	Diesel Fuel Tailpipe Emissions

The boundaries around each lifecycle stage include the emissions and energy use associated with that operation as well as upstream components that feed into it. For example, the corn farming stage includes emissions from fuel used in tractors as well as from producing and transporting the fertilizer used in the field. Electricity production emissions are included in almost all of the stages shown. These components typically have the biggest impact on the results. We did not include for example, energy and emissions associated with producing the steel and concrete used to construct the ethanol plants or petroleum refineries.

As other lifecycle studies of renewable fuels have included an expanded set of system boundaries, a sensitivity analysis was performed that includes the energy use and the emissions associated with producing farm equipment, and is described in section 6.1.2.7.

A potentially important system boundary affect, however, could be changes in land use. This is particularly the case for GHGs if new land (e.g., rainforest land) must first be cleared in order to grow the biofuel feedstocks. This lifecycle analysis is conducted without any regard to the geographic attributes of where emissions or energy use occurs. The benefits of this final rule represent global reductions in GHG emissions and energy use, not just those occurring in the U.S. For example, the savings associated with reducing overseas crude oil extraction and refining are included here, as are the international emissions associated with producing imported ethanol. One exception to this is the emissions associated with international land use change. Due to decreasing corn exports and modest decreases in soybean exports, there may be some additional corn and soybean acres planted internationally to meet world demand. The emissions associated with domestic land use change are included in our lifecycle analysis but international land use change was not as it was outside the scope of our agriculture sector analysis. However, if emissions from international land use change were included it would lower the overall benefits of this rule. This is an area we will continue to examine for future analysis.

6.1.1.3 Environmental Flows Considered

One issue that has come to the forefront in the assessment of the environmental impacts of transportation fuels relates to the effect that the use of such fuels could have on emissions of greenhouse gases (GHGs). The combustion of fossil fuels has been identified as a major contributor to the increase in concentrations of atmospheric carbon dioxide (CO_2) since the beginning of the industrialized era, as well as the build-up of trace GHGs such as methane (CH_4) and nitrous oxide (N_2O). This lifecycle analysis evaluates the impacts of increased renewable fuel use on greenhouse gas emissions.

The relative global warming contribution of emissions of various greenhouse gases is dependant on their radiative forcing, atmospheric lifetime, and other considerations. For example, on a mass basis, the radiative forcing of CH_4 is much higher than that of CO_2, but its effective atmospheric residence time is much lower. The relative warming impacts of various greenhouse gases, taking into account factors such as atmospheric lifetime and direct warming effects, are reported on a 'CO_2-equivalent' basis as global warming potentials (GWPs). The GWPs used in this analysis were developed by the UN Intergovernmental Panel on Climate Change (IPCC) as listed in their Third Assessment Report[C], and are shown in Table 6.1-2.

Table 6.1-2.
Global Warming Potentials for Greenhouse Gases

Greenhouse Gas	GWP
CO_2	1
CH_4	23
N_2O	296

Greenhouse gases are measured in terms of CO_2-equivalent emissions, which result from multiplying the GWP for each of the three pollutants shown in the above table by the mass of emissions for each pollutant. The sum of impacts for CH_4, N_2O, and CO_2, yields the total effective GHG impact.

The impact increased volumes of renewable fuels use has on GHG emissions (in terms of CO_2-eq.) as well as for only CO_2 emissions which represent a subset of the overall GHG emissions, is considered in this analysis. The impact increased volumes of renewable fuels use has on fossil energy (in terms of Btus) is also considered. Fossil energy use includes energy associated with coal, natural gas, and petroleum products. Fossil energy use is strongly linked with CO_2 and GHG emissions and is an important consideration when looking at overall sustainability.

[C] IPCC "Climate Change 2001: The Scientific Basis", Chapter 6; Intergovernmental Panel on Climate Change; J.T. Houghton, Y. Ding, D.J. Griggs, M. Noguer, P.J. van der Linden, X. Dai, C.A. Johnson, and K. Maskell, eds.; Cambridge University Press. Cambridge, U.K. 2001. http://www.grida.no/climate/ipcc_tar/wg1/index.htm

Petroleum energy use is a subset of fossil energy use and is the major contributor to overall transportation sector energy use. Petroleum energy use is also linked to CO_2 and GHG emissions but also has impacts on national energy concerns such as dependence on foreign sources of petroleum. Therefore, petroleum energy was also considered separately in this analysis and examined in terms of overall energy use, as well as in terms of petroleum imports avoided through the increased use of renewable fuels.

6.1.1.4 Time Frame and Volumes Considered

The results presented in this analysis represent a snapshot in time. They represent annual GHG and fossil fuel savings in the year considered, in this case 2012.

Consistent with the renewable fuel volume scenarios described in Chapter 2, our analysis of the GHG and fossil fuel consumption impacts of renewable fuel use was conducted using three volume scenarios. The first scenario was a reference case representing 2004 renewable fuel production levels, projected to 2012. This scenario provided the point of comparison for the other two scenarios. The other two renewable fuel scenarios for 2012 represented the RFS program requirements and the volume projected by EIA.

In both the RFS and EIA scenarios, we assumed that the biodiesel production volume would be 0.303 billion gallons based on an EIA projection. Furthermore, the Energy Act requires that 250 million gallons of cellulosic ethanol be produced starting in the year 2013, for both scenarios we assume that 250 million gallons of ethanol that qualify for cellulosic credit will be produced in 2012. The remaining renewable fuel volumes in each scenario would be ethanol made from corn and imports. The import volume is based on EIA's projections for the percent of total ethanol volume supplied by imports in 2012. The total volumes for all three scenarios are shown in Table 6.1-3.

Table 6.1-3. Volume Scenarios in 2012 (billion gallons)

	Reference Case	RFS Case	EIA Case
Corn-ethanol	3.947	5.985	8.758
Cellulosic ethanol	0.0	0.25	0.25
Biodiesel	0.030	0.303	0.303
Ethanol imports	0.0	0.436	0.630
Total volume	3.977	6.974	9.941

As we are comparing against a reference case, we are only interested in the emissions and energy savings associated with new or marginal renewable fuels production that comes on-line after 2004 (the baseline assumed for the reference case).

6.1.1.5 Model Used

The lifecycle model used in the evaluation of the impacts of the RFS program is the fuel-cycle model developed by DOE's Argonne National Laboratory. For this work, EPA used the most recent version of this model, GREET 1.7 (November 10, 2006 release). GREET, a multi-dimensional spreadsheet model, is one of the most widely used model of this type for transportation fuels. It has been reviewed, used, and referenced by a wide variety of analysts, including General Motors, National Corn Growers Association, several fuel industry organizations, and a wide variety of academic institutions. It is the most comprehensive and user-friendly model of its type. It has been under development for over 10 years, with input from EPA, USDA, DOE laboratories, and industry representatives. The model addresses the full lifecycle for an exhaustive number of alternative transportation fuels and automotive technologies. For these reasons, EPA felt it was the best tool for evaluating the energy and emission impacts of the RFS program.

The GREET model has been developed to calculate per-mile energy use and emission rates of various combinations of vehicle technologies and fuels for both fuel cycles and total energy cycles. The model actually consists of three components: GREET 1.x, which calculates fuel cycle energy use and emissions, GREET 2.x, which calculates light-duty vehicle cycle energy use and emissions, and GREET 3.x, which calculates heavy-duty vehicle cycle energy use and emissions. All discussion here refers to GREET 1.7, the most recent version of the fuel component of GREET.

To estimate fuel cycle energy use and emissions, GREET first estimates energy use and emissions for a given upstream stage. The model then combines the energy use and emissions from all upstream stages for a fuel cycle, to estimate total upstream fuel cycle energy use and emissions. Inputs are national-average energy usage rates, efficiencies and emission factors for each stage. The model calculates total energy use, fossil energy use, and emission rates for the regulated pollutants and greenhouse gases, reported as grams per mile or grams per million Btu. These results allow comparison of transportation fuels, based on energy use and/or emissions.

One of the main comments we received on our lifecycle approach was that our sole reliance on the GREET model should be avoided, given other models are available. There are several other models that have been developed for conducting renewable fuels lifecycle analysis. For example, researchers at the Energy and Resources Group (ERG) of the University of California Berkeley have developed the ERG Biofuel Analysis Meta-Model (EBAMM) and Mark Delucchi at the Institute of Transportation Studies of the University of California Davis has developed the Lifecycle Emissions Model (LEM). There are also other non-fuel specific lifecycle modeling tools that can be used to perform renewable fuel lifecycle analysis. The main differences in these models are with input assumptions used as described below.

Several studies have been released recently making use of these other models and showing different results than we find in the analysis done for this rule. For example, whereas GREET estimates a net GHG reduction of about 22% for corn ethanol compared to gasoline, the previously cited works by Farrell et al. utilizing the EBAMM show around a 13% reduction. While there may be small differences in the models in terms of emissions and energy uses associated with ancillaries (e.g., emissions to produce fertilizer, electricity, etc.) the main difference in results is not due to model used but assumptions on scope and input data used.

For example, most studies focus on average or current ethanol production which uses a current mix of wet and dry mill ethanol production and use of coal and natural gas as process energy. In contrast, we consider new or marginal ethanol production which implies a higher portion of more efficient dry mill production and mix of process fuels. Other studies also typically base ethanol and farm energy use on historic data while we are assuming a state of the art dry milling plant and most current farming energy use data. Assumptions concerning land use change CO_2 emissions and agriculture related GHG emissions could also have an impact on overall results. Other studies also differ in the environmental flows considered. For example, Delucchi[1] uses different types of greenhouse gases and GWPs compared to those used in this analysis as shown in Table 6.1-2 to determine GHG emissions.

Other researchers have performed lifecycle analysis of renewable fuels not specifically focused on GHG emissions. One result that has been debated recently is the net energy balance of corn-based ethanol fuel. Some analysts have suggested that there is actually a negative energy balance for corn ethanol, meaning that it takes more fossil energy to produce the ethanol than is contained in the resulting fuel, making it an unattractive transportation fuel. While we do not believe this is an appropriate metric to use when examining renewable fuels, as discussed in Section 6.2.3, it is still useful in examining the range of lifecycle results. Two studies Pimental (2003)[D] and Patzek (2005), [E] concluded that the energy balance is negative. . Many other researchers, however, have criticized that work as being based on out-dated farming and ethanol production data, including data not normally considered in lifecycle analysis for fuels, and not following the standard methodology for lifecycle analysis in terms of valuing co-products. Furthermore, several recent surveys have concluded that the energy balance is positive, although they differ in their numerical estimates.[F,G,H] Authors of the GREET model have also concluded that the lifecycle amount of fossil energy used to produce ethanol is less than the amount of energy in the ethanol itself. Based on our review of all the available information, and the results of our own analysis, we also believe that the energy balance is positive.

The differences found by different studies and models used emphasize the importance of the input data and methodology when using lifecycle analysis. It also shows how dependent this type of analysis is on the assumptions made throughout the model. Based on differences in scopes and input data considered between these other studies and what we defined in this

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[D] Pimentel, David “Ethanol Fuel: Energy Balance, Economics, and Environmental Impacts are Negative”, Vol. 12, No 2, 2003 International Association for Mathematical Geology, Natural Resources Research

[E] Pimentel, D.; Patzek, T. "Ethanol production using corn, switchgrass, and wood; biodiesel production using soybean and sunflower." Nat. Resour. Res. 2005, 14 (1), 65-76.

[F] Hammerschlag, R. "Ethanol's Energy Return on Investment: A Survey of the Literature 1990 - Present." Environ. Sci. Technol. 2006, 40, 1744 - 1750.

[G] Farrell, A., Pelvin, R., Turner, B., Joenes, A., O’Hare, M., Kammen, D., “Ethanol Can Contribute to Energy and Environmental Goals”, Science, 1/27/2006, Vol 311, 506-508.

[H] Hill, J., Nelson, E., Tilman, D., Polasky, S., Tiffany, D., “Environmental, economic, and energetic costs and benefits of biodiesel and ethanol biofuels”, Proceedings of the National Academy of Sciences, 7/25/2006, Vol. 103, No. 30, 11206-11210.

analysis, we believe the differences in results that are seen are reasonable and the values we are obtaining from our use of the GREET model are acceptable for this analysis.

6.1.2 Modifications to GREET

EPA chose to use GREET 1.7 to evaluate the lifecycle impacts of the RFS program. GREET 1.7 is the most recently released version of the GREET model. However, this version of the model does not reflect the potential impacts on transportation fuel industries as a result of the RFS program. In addition, for this regulation our intent was to evaluate the impact of incremental renewable fuel production resulting from the RFS program and not a current industry average. Therefore, EPA has modified some of the input variables and assumptions made in the GREET model. The renewable fuels considered in this analysis were modeled as being produced from the following feedstocks and processes:

- Corn Ethanol:
  - Wet Milling
    - Mix of coal and natural gas as process fuel
  - Dry Milling
    - Natural gas as process fuel
    - Coal as process fuel
    - Biomass as process fuel

- Cellulosic Ethanol:
  - Hybrid Poplar Feedstock
    - Fermentation route
  - Switchgrass Feedstock
    - Fermentation route
  - Corn Stover Feedstock
    - Fermentation route
  - Forest Waste Feedstock
    - Gasification route

- Biodiesel:
  - Soybean Oil Feedstock
    - Transesterification route
  - Yellow Grease Feedstock
    - Transesterification route

These feedstocks and processes were primarily based on what was available in the GREET model with some minor modifications as described below. However, there are other pathways for producing renewable fuels not covered here, for example different feedstocks for cellulosic ethanol production (e.g., MSW) as well as different process for the feedstocks considered, like gasification of switchgrass and production of soybean oil diesel fuel through hydrotreating.

Furthermore, the lifecycle analysis used for this rulemaking is based on averages of the different renewable fuels modeled. For example, the GHG emission and fossil energy savings associated with increased use of corn ethanol are calculated based on a mix of process fuels, assuming a certain projected mix of each process fuel as outlined below. While this method may not exactly represent the reductions associated with a given gallon of renewable fuel, it is reasonable for the purpose of this analysis which is to determine the impact of the total increased volume of renewable fuels used.

We recognize that different feedstocks and processes will each have unique characteristics when it comes to lifecycle GHG emissions and energy use. However, we understand that other feedstocks and processes as well as differences in other parts of the renewable fuel lifecycle will impact the savings associated with their use and this is the focus of ongoing work at the agency.

GREET is subject to periodic updates by ANL, each of which results in some changes to the inputs and assumptions that form the basis for the lifecycle estimates of emissions generated and energy consumed. These updates generally focus on those input values for those fuels or vehicle technologies that are the focus of ANL at the time. As a result there are a variety of other inputs related to ethanol and biodiesel that may not have been updated in some time. In the context of the analysis of the RFS and EIA scenarios, we determined that some of the GREET input values that were either based on outdated information or did not appropriately reflect market conditions under a renewable fuels mandate should be examined more closely, and updated if necessary.

Since the analysis done for the NPRM, several changes have been made to the GREET model, some as part of periodic updates ANL had planned and some as part of an interagency agreement between ANL and EPA to investigate a variety of GREET input values. A summary of the changes is as follows:

- Included CO_2 emissions from corn farming lime use
- Updated the corn farming fertilizer use inputs
- Added cellulosic ethanol production from corn stover and forest waste
- Modeled biomass as a process fuel source in corn ethanol dry milling

In addition to the changes above we also examined and updated other GREET input assumptions for corn ethanol and biodiesel production. A summary of the GREET input values we investigated and modified is given below. We also examined several other GREET input values, but determined that the default GREET values should not be changed for a variety of reasons as discussed in the following sections. These included corn and ethanol transport distances and modes and byproduct allocation methods. Our investigation of these other GREET input values are discussed more fully below. The current GREET default factors for these other inputs were included in the analysis for this final rule.

We did not investigate the input values associated with the production of petroleum-based gasoline or diesel fuel in the GREET model for this final rule. However, the refinery modeling discussed in Chapter 7 will provide some additional information on the process energy requirements associated with the production of gasoline and diesel under a renewable fuels mandate. We will use information from this refinery modeling in future analysis to determine if any GREET input values should be changed.

A summary of the GREET corn ethanol input values we investigated for this final rule is given below.

6.1.2.1 Wet Mill versus Dry Mill Ethanol Plants

As described in Chapter 1, the two basic methods for producing ethanol from corn are dry milling and wet milling. In the dry milling process, the entire corn kernel is ground and fermented to produce ethanol. The remaining components of the corn are then dried for animal feed (dried distillers grains with solubles, or DDGS). In the wet milling process, the corn is soaked to separate the starch, used to make ethanol, from the other components of the corn kernel. Wet milling is more complicated and expensive than dry milling, but it produces more valuable products (ethanol plus corn syrup, corn oil, and corn gluten meal and feeds). The majority of ethanol plants in the United States are dry mill plants, which produce ethanol more simply and efficiently.

While other lifecycle models often base the mix of wet and dry milling on existing plants, for this analysis, we are only interested in marginal ethanol production. We expect most new ethanol plants will be dry mill operations. That has been the trend in the last few years as the demand for ethanol has grown, and our analysis of ethanol plants under construction and planned for the near future has verified this. Our analysis of production plans, as outlined in Chapter 1, indicates that essentially all new ethanol production will be from dry mill plants (99%).

6.1.2.2 Coal versus Natural Gas in Ethanol Plants

The type of fuel used within the ethanol plant for process energy to power the various components that are used in ethanol production (dryers, grinders, heating, etc.) can vary among ethanol plants. The type of fuel used has an impact on the energy usage, efficiency, and emissions of the plant, and is primarily determined by economics. Most new dry mill plants built in the last few years have used natural gas. However, some new plants are using coal. For these cases, EPA is promoting the use of combined heat and power, or cogeneration, in ethanol plants to improve plant energy-efficiency and to reduce air emissions. This technology, in the face of increasing natural gas prices, may make coal a more attractive energy source for new ethanol plants.

GREET default factors represent the average percentage of fuel use for the entire industry, and may not reflect the recent growth in the industry. Therefore, we based our fuel mix assumptions on the review of plants under construction and those planned for the near future outlined in Chapter 1. Our analysis indicates that coal will be used as process fuel for approximately 14% of the new dry mill under construction and planned ethanol production volume capacity. This is the value we used in GREET for our analysis of dry milling ethanol production fuel mix.

As opposed to typical dry mill plants, corn wet mill ethanol plants can use a mix of process fuel sources at the same plant. For the 1% of additional ethanol production from wet mills, the GREET model defaults of 40% coal and 60% natural gas process fuel was used in this analysis.

As described below, the ethanol production stage of the lifecycle typically represents the stage where the largest amount of fossil fuel energy is consumed and where the impact on lifecycle emissions is the greatest. Therefore, the type of process fuel used in ethanol production will have a significant impact on the fuel's lifecycle GHG results. For example, our analysis indicates that ethanol produced in a coal fired dry mill plant would not have any GHG benefits as compared to petroleum gasoline. Given that the relative prices of natural gas and coal could change over time, and thus change the percentage of each used in ethanol production, our analysis of fuels used in plants under construction and those planned for the future would need to be reevaluated for future work.

6.1.2.3 Ethanol Plant Process Efficiency

For the corn-to-ethanol fuel cycle, the largest amount of fossil fuel energy consumed occurs at the ethanol production plant. The energy use at a dry mill plant using natural gas was based on the model developed by USDA which was documented in a peer-reviewed journal paper on cost modeling of the dry-grind corn ethanol process.[2] This model was modified by EPA for use in the cost analysis of this rulemaking described in Chapter 7. GREET inputs are total energy use per gallon of ethanol produced. The USDA model predicts the annual thermal (natural gas) and electricity demand shown in Table 6.1-4.

Table 6.1-4.
Annual Energy Use at Dry Mill Ethanol Plant

Energy Input	Value
Purchased Electricity (MWh/yr.)	41,308
Natural Gas (mmBtu/yr.)	1,617,094
Output	
Ethanol (mmgal/yr.)	50

Electricity energy use was converted from MWh to Btu based on a conversion of 3,410 btu/kWh. The primary energy used to produce electricity is accounted for in the GREET model. Table 6.1-5 shows the GREET input used for natural gas process fuel dry milling plants in this analysis.

Table 6.1-5.
GREET Inputs for Corn Ethanol
Natural Gas Dry Mill Energy Use

Total Energy Use (mmBtu/gal.)	35,159
% electricity	8.0%

Energy requirements for a coal fired ethanol plant are different from a natural gas fired plant. Typically coal boilers are slightly less efficient than natural gas boilers. Furthermore additional electricity is required for coal storage and handling as compared to natural gas. Additionally a large portion of the energy at an ethanol plant is due to drying the DDGS. A natural gas plant utilizes natural gas driers for this process while a coal fired plant would use steam dryers, the efficiency loss of converting coal to steam represents additional thermal energy required at a coal fired plant vs. a natural gas one.

Most other lifecycle models assume the same energy efficiency for both coal and natural gas ethanol plants, however, for this analysis, it was assumed that a coal plant would require 15%[I] more electricity demand due to coal handling and have a 13% increase in thermal demand for steam dryers as compared to the natural gas fueled plant. The increase in thermal demand was based on breaking out the drying energy in the USDA process model and assuming the same amount of energy would be produced by 78% efficient coal boilers. Table 6.1-6 shows the GREET input used for coal process fuel dry milling plants in this analysis.

Table 6.1-6.
GREET Inputs for Corn Ethanol
Coal Dry Mill Energy Use

Total Energy Use (mmBtu/gal.)	40,079
% electricity	8.1%

The Energy Act also allows ethanol made from non-cellulosic feedstocks to receive cellulosic ethanol production volume credit if 90 percent of the process energy used to operate the facility is derived from a renewable source. In the context of our cost analysis, we have assumed that 250 million gallons of corn ethanol will be produced using 90 percent or more biomass energy and receive the cellulosic ethanol volume credit. Further discussion of this issue can be found in Chapter 1.

For the lifecycle analysis we considered the case where a corn ethanol dry mill plant utilized biomass as a fuel source. For this case the same amount of fuel and purchased electricity energy per gallon as a coal powered plant was assumed. This assumption is based on the biomass plant having more fuel handling than a natural gas plant and producing steam for DDGS drying.

As discussed in section 6.2.3, CO_2 emissions from combustion of biomass are not assumed to increase net atmospheric CO_2 levels. Therefore, CO_2 emissions from biomass combustion as a process fuel source are not included in the lifecycle GHG inventory of the ethanol plant. The fossil energy use and GHG emissions from producing the electricity used at the plant are included.

[I] Baseline Energy Consumption Estimates for Natural Gas and Coal-based Ethanol Plants - The Potential Impact of Combined Heat and Power (CHP), Prepared for: U.S. Environmental Protection Agency Combined Heat & Power Partnership, Prepared by: Energy and Environmental Analysis, Inc., July 2006.

For the 1% of corn ethanol produced from wet milling, the GREET process energy use default of 49,950 Btu/gallon of ethanol produced by the wet milling process was used in the analysis.

6.1.2.4 Corn Transport Distances

Corn transport distances selected for use in this analysis are 100 miles round trip. Corn used in the ethanol production process is assumed to travel from corn fields to ethanol production facilities in a two-step process; first, corn is transported from outlaying farms to centrally-located collection facilities, such as county elevators. Second, this corn is transported from the collection facilities to the ethanol production facilities. The first leg of the corn transport process is assumed to be a 20-mile round trip and the second leg is assumed to be an 80-mile round trip. These assumptions coincide with those used in GREET[3] Version 1.7 and GREET Version 1.5.

Corn transport data is limited, however; Graboski[J] found that the average one-way hauling distance for corn from fields to county elevators was 7.5 miles and from county elevators to ethanol processing facilities was 49.7 miles for an effective average round-trip corn transport distance of 74.6 miles. Similarly, Gervais and Baumel[4] found that average one-way corn transport distances for the 1994-1995 Iowa growing season was 37.2 miles for semi-trucks (35.8%), 4.9 miles for wagons (33.3%), and 9.1 miles for single and tandem axel vehicles (30.9%). Several Minnesota corn mills indicated that the maximum radius of supply for their mills was 65 to 80 miles (values apparently cited in the same study).

The available data on corn transport distances does not provide a clear indication that the default values in GREET are unreasonable. Therefore, we retained the GREET default values for our analysis. This assumes that the land use pattern (where corn is planted) and the plant location decisions by ethanol plants will not change significantly. We believe this is reasonable for the fuel volumes considered. This is an area we will continue to examine for future analysis.

6.1.2.5 Ethanol Transportation Distances and Modes

The default values in GREET for ethanol transportation and modes are shown in Table 6.1-7. These values correspond to numbers in a USDA study on the energy balance of corn ethanol.[5]

[J] The authors assume that the corn payload weight is equal to the transport vehicle weight, that the vehicle returns empty, and the effective average round-trip vehicle distance can be estimated as being one and a half times the one-way travel distance (1.5 times 49.7 miles = 74.6 miles); Graboski, 2002, *Fossil Energy Use in the Manufacture of Corn Ethanol*, Colorado School of Mines, (Prepared for the National Corn Growers Association).

Table 6.1-7. GREET Ethanol Transportation Input Data

Mode	Plant to Terminal		Terminal to Station	
	%	Distance (miles)	%	Distance (miles)
Rail	40%	800	0%	
Barge	40%	520	0%	
Truck	20%	80	100%	30

The GREET default values are consistent with the analysis we performed on ethanol distribution infrastructure. Chapter 1 of this document discusses current ethanol transportation and distribution and indicates that if ethanol facilities are located within 100-200 miles of a terminal, trucking is preferred. Rail and barge are used for longer distances. Pipelines are not currently used to transport ethanol and are not projected to play a role in ethanol transport in the future time frame considered.

We also discuss in Chapter 1 future ethanol transportation and distribution needs based on the increased amounts of renewable fuels used as a result of this rule. We concluded that most new ethanol capacity will not have river access. In addition, at least one new ethanol plant slated for production that does have river access is planning to move its ethanol to market via rail so most new ethanol freight volumes will be handled by rail and that ethanol transport by inland waterway will remain constant.

A recent USDA Cost of Ethanol Production report also provides information on ethanol distribution distances and modes.[6] The report includes 2002 data from a survey of 21 dry mill ethanol plants. The survey collected data on modes and distances traveled for ethanol transport from the facilities. The report concluded that 46 percent of the ethanol produced at the surveyed plants in 2002 was shipped by truck an average one way distance of 93 miles, with a range of 30 to 250 miles. The remaining 54 percent of ethanol produced was shipped by rail an average one way distance of 1,163 miles, with a range of 800 to 2,500 miles. However, this data is for a subset of existing plants where, for example, there is no barge transportation listed, and also does not take into account the increased demand for ethanol projected by this rule.

Comparing the GREET default values to these other sources indicates that the GREET defaults values for percent of ethanol transported by rail may be low. However, due to lack of precise data on future ethanol transportation by mode, we concluded that the current GREET default values for percent of ethanol transported by mode are appropriate for the RFS analysis.

The GREET default values for miles shipped by mode fall within the range of values listed in the USDA survey data of existing plants. The USDA survey data indicate higher than average transportation distances; however the data is not comprehensive enough, only representing a small fraction of total and projected ethanol production capacity, thus not warranting a change to the default GREET values. Therefore, the default values shown in Table 6.1-7 were used in this analysis. This is an area we will continue to examine for future analysis.

6.1.2.6 Biodiesel Transportation Distances and Modes

The default values in GREET for biodiesel transportation and modes are shown in Table 6.1-8.

Table 6.1-8. GREET Biodiesel Transportation Input Data

Mode	**Plant to Terminal**		**Terminal to Station**	
	%	Distance (miles)	%	Distance (miles)
Barge	8%	520	0%	
Pipeline	63%	400	0%	
Rail	29%	800	0%	
Truck	0%		100%	30

The GREET default assumptions for mode of biodiesel transportation are not consistent with the analysis we performed on biodiesel distribution infrastructure. The distribution infrastructure discussion in Chapter 1 of this document indicates pipelines are not currently used to transport biodiesel and are not projected to play a role in biodiesel transport in the future time frame considered.

Therefore, GREET default factors for biodiesel transportation from plant to terminal were modified to remove pipeline transport. The percent of biodiesel shipped by barge and rail were increased in the same proportion as the current percentage split. The result was 22% of biodiesel shipped by barge and 78% shipped by rail. The GREET default distances for biodiesel rail and barge transport as well as terminal to station assumptions are consistent with ethanol transportation and distribution assumptions and were used in this analysis.

6.1.2.7 Corn Yield and Related Inputs

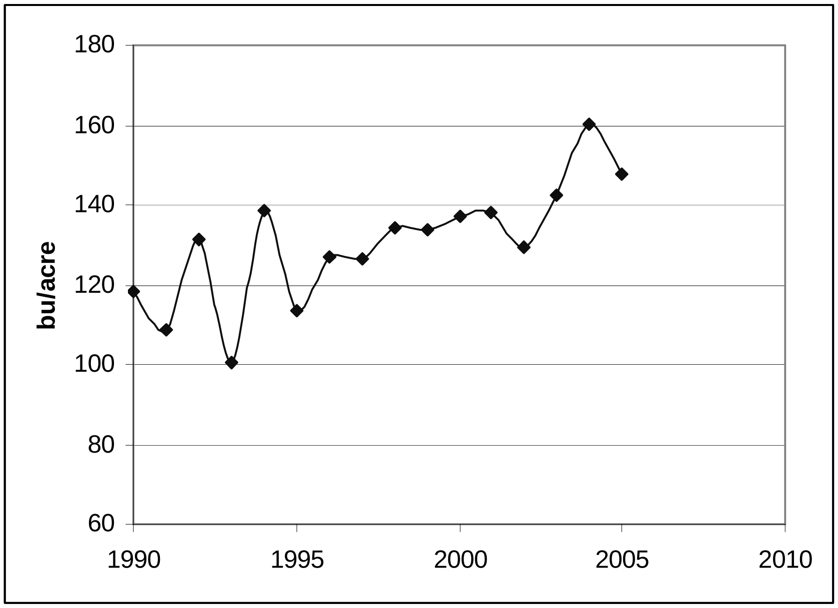
GREET includes a collection of energy use and material inputs to corn farming per bushel (bu) of corn produced. Several corn farming input data parameters and default values were updated from the version of GREET used for the NPRM to the version used in the FRM analysis. The current GREET corn farming input data default values are shown in Table 6.1-9.

Table 6.1-9. GREET Corn Farming Input Data

Input Parameter	Default Value
Energy Use for Corn Farming	22,500 Btu/bu
- Energy use from diesel fuel	38.3%
- Energy use from gasoline	12.3%
- Energy use from natural gas	21.5%
- Energy use from LPG	18.8%
- Energy use from purchased electricity	9.0%
Nitrogen Fertilizer (as N)	420 g/bu
Phosphate Fertilizer (as P_2O_5)	149 g/bu
Potash Fertilizer (as K_2O)	174 g/bu
Lime (as $CaCO_3$)	1,202 g/bu
Herbicide Use:	8.1 g/bu
Insecticide Use:	0.68 g/bu

The default GREET input values for corn farming shown in Table 6.1-9 are based in part on farm energy use and material inputs per acre divided by an assumed corn yield in bu/acre. Therefore, while corn yield is not a direct input in GREET, it is a critical part of the calculation of corn energy and material input requirements. Although corn yields have been generally rising over time, see Figure 6.1-2, the annual variation is volatile.

Figure 6.1-2. U.S. Average Corn Yield[7]



We examined data on farm energy use, material input, and yield data to determine if the GREET default values needed to be updated. The lifecycle modeling conducted for the RFS program is based on future predictions. Unfortunately, no good projections of future energy use associated with corn farming are available. USDA does list projections for corn yield. The 2012 projected U.S. average corn yield is 158.5 bu/acre.[8] Historic data on corn farming energy use is available from the following USDA information sources.

- The USDA Agricultural Resource Management Survey (ARMS) provides data from selected States on fuel, electricity, natural gas, and seed corn used per acre on the farm and activities of moving farm products to initial storage facilities.
- The USDA National Agricultural Statistics Service (NASS) produces annual data on crop production including yields per acre and total production of corn by state.

USDA NASS data on corn yields and production values are provided annually. However, the three most recent years of the ARMS data and specifically the costs-of-production portion of the survey dedicated to corn are 1991, 1996, and 2001[K]. Table 6.1-10 lists corn farming energy input data for the three years of the ARMS study.

[K] Use of historic farming energy use may not be representative of current practice. Higher energy prices relative to the years considered here could lead to farmers adopting practices that lower overall energy use.

Table 6.1-10. Farm Energy Use Data per Acre

Input	Units	9-State Weighted Average Values			
		1991	1996[a]	2001	3 Yr. Avg.
Seed	bu/acre	1.51	1.50	1.69	1.57
Energy:					
- Diesel	Gallons/acre	7.81	9.80	6.40	8.01
- Gasoline	Gallons/acre	3.42	3.07	1.65	2.71
- LPG	Gallons/acre	3.86	7.25	5.10	5.41
- Electricity	kWh/acre	32.72	79.38	38.22	50.11
- Natural Gas	Cubic ft/acre	284.73	208.12	207.09	233.31
Total Energy Use	mmBtu/acre	2.12	2.71	1.78	2.20

[a] High energy use in the 1996 survey is due to increased corn drying requirements. See the discussion below.

Although USDA corn data is available for every state that produces corn, the data documented in Table 6.1-10 is for nine major corn producing States: Illinois, Indiana, Iowa, Minnesota, Nebraska, Ohio, Michigan, South Dakota, and Wisconsin. In 2005, these nine States accounted for 80 percent of U.S. corn production. In 2001 these nine States represented 92 percent of U.S. ethanol production, and based on our analysis outlined in Chapter 1 are projected to represent 82 percent of ethanol production in 2012. The data in Table 6.1-10 are weighted based on corn production data for each of the nine States from the NASS. The total energy use values listed in Table 6.1-10 were calculated by converting fuel use to Btu based on the lower heating values of the fuels as listed in the GREET model. These estimates may be biased downward if the corn production attributable to the incremental increase in ethanol production will occur on less productive land than was used in the 1991-2001 period, when corn prices were lower than they are projected to be in this analysis. Also, as corn production expands due to expanded ethanol production, it may increasingly take place in dryer climates that may increase irrigation demand and result in different yields. This is an area we will continue to examine for future analysis.

The ARMS surveys include information on energy use and also on dollars spent by famers on custom work. This custom work includes farmers contracting outside services for corn drying, planting, fertilizing and harvesting. The cost of custom work includes machine overhead, fuel charges, and labor costs. Therefore, there is some energy use associated with the dollars spent on fuel used in custom work. It was assumed that 10% of custom work cost was spent on fuel[9]. This fuel cost was assumed to be split between LPG and diesel fuel in the same percentage as reported energy use for each state. Cost was converted to gallons based on price paid by farmers for LPG and diesel fuel in each of the survey years[10]. Custom work energy use is included in Table 6.1-10.

It can be seen from Table 6.1-10 that there is substantial variation in the three years of energy use survey data. Several factors can influence corn farming energy use. For example, it was reported that 1991 was a dry year, lowering the moisture content of the corn crop and thus requiring less energy to dry the corn, whereas the 1996 crop was reported to have a higher moisture content and thus require more energy to dry resulting in the high energy use values for

1996. Farm diesel use is also dependent on tillage type and soil conditions, wetter soil requiring more diesel use, and decreased tillage requirements (e.g., no till) reducing diesel use.[11]

To project corn farming fuel use in 2012, the average energy use from the three years of survey data were taken, in terms of energy per acre. As energy use is somewhat weather related and it is impossible to confidently predict future conditions, it was felt that the three years of historic data represented a good mix of high and low energy use years. The average energy use in terms of Btu/acre was divided by the projected corn yield in 2012 of 156.9 bu/acre. This is the USDA projected corn yield adjusted to account for seed corn energy use as shown in Table 6.1-10. The seed use shown in Table 6.1-10 accounts for seed corn energy use. We assumed that growing seed corn requires 4.7 times the energy and material inputs to grow than corn[12,13]. The result was 14,036 Btu of energy needed to produce a bushel of corn, which was used in GREET for this analysis.

The GREET default values for corn farming material inputs were updated from the values in the NPRM version. GREET defaults were based on historic data provided from the following USDA sources.

- The USDA National Agricultural Statistics Service (NASS) produces annual reports listing quantities of fertilizers and chemicals used per acre of corn.
- The USDA Economic Research Service (ERS) produces an Agricultural Resources and Environmental Indicators report that has data on lime used per acre of corn.

The USDA sources provide average material use data per harvested acre of corn. The GREET defaults are based on the assumption that material input use per acre will be flat from 2005 into the future. The 2005 values are based on a three year average of 2003 through 2005 data. Data on inputs per acre are divided by projected corn yields to get GREET defaults in terms of g/bushel of corn. While these values are felt to be reasonable to be used in this analysis, the agency cautions that these estimates are based on the historical record while the incremental corn production attributable to expanded ethanol production may occur on less productive land than was used historically. As a result, these estimates may be biased downward, resulting in over-estimates of ethanol displacement indices.

Another potential input to corn farming is the energy and emissions associated with producing farm equipment. As described in Section 6.1.1.2, this input is considered outside the system boundaries of our lifecycle analysis. However, the latest version of GREET has an option to include energy use and emissions associated with producing farm equipment in the corn ethanol lifecycle results. We performed a sensitivity analysis on expanding the corn production system to include farm equipment production to determine the impact it has on the overall results of our analysis.

It was found that including farm equipment production energy use and emissions increases ethanol lifecycle energy use and GHG emissions and decreases the corn ethanol displacement index by approximately 1 percent. Furthermore, to be consistent in the modeling if system boundaries are expanded to include production of farming equipment they should also be expanded to include producing other material inputs to both the ethanol and petroleum lifecycles.

For example, this expansion of system boundaries would include the energy use and emissions associated with producing concrete and steel used in the petroleum refinery[L]. The net effect of this would be a slight increase in both the ethanol and petroleum fuel lifecycle results and a smaller or negligible effect on the comparison of the two.

The corn farming material and energy use used in the lifecycle analysis is based on producing and average bushel of corn. There are differences associated with variations in corn yield, inputs required for existing land vs. land converted to crops, etc. Furthermore, there are ripple effects associated with increased corn used for ethanol that could have GHG emission implications, ranging from changes in manure management to the acres of rice grown. One such effect is CO_2 associated with land use change which is examined in the following section. Other effects and variations in corn farming will be examined as part of future analysis.

6.1.2.8 CO_2 from Land Use Change

Farming practices could potentially release carbon stored in soil as CO_2 emissions. If non-cropland (e.g., pastureland, Conservation Reserve Program (CRP) land) is converted to crop production, carbon sequestered in the soil and existing cover could be released. The agricultural sector modeling work done for this rulemaking examined the issue of land use change due to increases in renewable fuel production and use. The agricultural sector modeling results indicate that, compared to the 2012 Reference Case, approximately two and a half million acres will come out of CRP land as a result of increased renewable fuel production. Not all of these two million acres will go directly into corn production used to produce ethanol. However, the entire amount of CO_2 emissions from the CRP land use change is attributable to the increased amount of ethanol produced, as without the increased demand for corn there would be no change in CRP land. The agricultural modeling results also indicated a reduction in U.S. corn exports and a modest decline in U.S. soybean exports which could impact crop production in other countries. However, we did not consider impacts on non-U.S. land use that might result from decrease in U.S. exports of corn and soybeans.

The GREET model has a default factor for CO_2 from land use change that was included in the NPRM analysis. This factor was updated based on the results of the agricultural sector modeling mentioned above and included in the final rulemaking lifecycle analysis. The CO_2 emissions from land use change used in the final rulemaking represent approximately 1% of total corn ethanol lifecycle GHG emissions. However, this value could be more significant if increased amounts of renewable fuels are used.

The issue of CO_2 emissions from land use change associated with converting forest or CRP land into crop production for use in producing renewable fuels is an important factor to consider when determining the overall sustainability of renewable fuel use. While the analysis described above is indicating that this rulemaking will not cause a significant change in land use, this is an area we will continue to research for any future analysis.

6.1.2.9 Ethanol Production Yield

[L] The expansion of system boundaries would apply to existing refineries as ethanol is assumed to replace gasoline from existing production.

Modern ethanol plants are now able to produce more than 2.7 gallons of ethanol per bushel of corn compared with less than 2.4 gallons of ethanol per bushel of corn in 1980. The development of new enzymes continues to increase the potential ethanol yield. We used a value of 2.71[M] gal/bu in our analysis, which may underestimate actual future yields. However, this value is consistent with the ethanol model developed by USDA described in Section 6.1.2.2 and was used in the cost modeling of corn ethanol discussed in Chapter 7.

6.1.2.10 Byproduct Allocation

There are a number of by-products made during the production of ethanol. In lifecycle analyses, the energy consumed and emissions generated by an ethanol plant must be allocated not only to ethanol, but also to each of the by-products. There are a number of methods that can be used to estimate by-product allocations. These include methods based on the economic value of each by-product, or on energy usage, based on engineering analysis of the actual processes related to each product. The method preferred by EPA is called the displacement method. This method most accurately accounts for these by-products by calculating the lifecycle emissions of the products that will be displaced by them. In this method the lifecycle emissions of the displaced product are calculated and subtracted from the ethanol lifecycle. The ethanol receives a credit for the lifecycle emissions of whatever product is displaced, since a quantity of that product is no longer needed and is displaced by the ethanol by-products.

For example, the DDGS produced by an ethanol dry mill plant is a replacement for corn and soybean animal feed. We based the amount of DDGS produced by an ethanol dry mill plant on the USDA model used in the cost analysis work of this rulemaking. That model predicted 6.21 dry lb. of DDGS per gallon of ethanol produced. As per the agricultural sector modeling done for this rulemaking, we assumed that this DDGS displaces 50% corn and 50% soybean meal on a mass basis. So the lifecycle emissions of producing 3.1 lb. of corn and 3.1 lb. of soybean meal were calculated and subtracted from the lifecycle emissions associated with producing a gallon of ethanol.

By-products from the ethanol wet milling process include corn gluten meal and corn gluten feed that are assumed to displace corn production, as well as corn oil that is assumed to displace soybean oil. Ethanol produced from cellulosic feedstock through the fermentation route is assumed to produce excess electricity as a by-product, from onsite combustion of lignin. This excess electricity is assumed to displace electricity from the grid. The fermentation process used to produce ethanol in corn wet and dry milling and cellulosic ethanol production also produces CO_2 as a by-product. This CO_2 could be sold to an organization that specializes in cleaning and pressurizing it for use in the food industry for example to carbonate beverages, to manufacture dry ice, and to flash freeze meat. While CO_2 could potentially displace other sources of CO_2 production, this was not considered in our analysis and no value was associated with this CO2 co-product.

[M] All yield values presented represent pure ethanol production (i.e. no denaturant).

The displacement method for by-product allocation is the default for the GREET model. EPA supports that approach and continues to use that method in this analysis. However, other researchers have used different allocation methods in their ethanol fuel cycle studies. We evaluated one of these other methods used by USDA in a recent ethanol energy balance report[14] to determine the impact this assumption has on the overall results of the analysis. The method used by USDA was to split the energy use and emissions of corn agriculture and ethanol production between the ethanol and co-products. The lifecycle analysis results were then based on only the ethanol portion. A process simulation was used to allocate the energy used in the ethanol plant to ethanol and by-products. Using this approach they determined that on average 59 and 64 percent of the energy used in dry and wet mills respectively is used to produce ethanol. The remaining energy is used for the production of by-products. Therefore, for dry mill ethanol production only 59 percent of the plant energy use and associated emissions were allocated to the ethanol lifecycle. Corn production energy use and emissions were allocated based on the starch content of the corn, assumed to be 66 percent of corn kernel weight. So, only 66 percent of the energy and emissions used to produce corn were allocated to the ethanol lifecycle.

Use of the process energy based allocation method reduces ethanol lifecycle energy use and GHG emissions by approximately 30 percent compared to the displacement allocation approach. This indicates that ethanol lifecycle analysis results are extremely sensitive to the choice of allocation method used. However, as mentioned above, EPA feels that the displacement allocation method is the most reasonable and is the preferred method to use. This decision is supported by international lifecycle assessment standards which indicate that whenever possible the product system should be expanded to include the additional functions related to the co-products[15].

6.1.2.11 Biodiesel Production

Two scenarios for biodiesel production were considered, one utilizing soybean oil as a feedstock and one using yellow grease.

For the soybean oil scenario, the energy use and inputs for the biodiesel production process were based on a model developed by NREL and used by EPA in the cost modeling of soybean oil biodiesel, as discussed in Chapter 7.

The GREET model does not have a specific case of biodiesel production from yellow grease. Therefore, as a surrogate we used the soybean oil based model with several adjustments. For the yellow grease case, no soybean agriculture emissions or energy use was included. Soybean crushing was still included as a surrogate for yellow grease processing (purification, water removal, etc.). Also, due to additional processing requirements, the energy use associated with producing biodiesel from yellow grease is higher than for soybean oil biodiesel production. As per the cost modeling of yellow grease biodiesel discussed in Chapter 7, the energy use for yellow grease biodiesel production was assumed to be 1.72 times the energy used for soybean oil biodiesel.

The biodiesel lifecycle results were based on a 50% / 50% split between soybean oil and yellow grease biodiesel production based on EIA's AEO 2006 projections for biodiesel produced from the different feedstocks.

6.2 Methodology

As outlined in the scoping discussion, the goals of this analysis are to both examine the total GHG and fossil fuel reductions of increased renewable fuel use in absolute tons and gallons and to compare these reductions to the U.S. transportation sector and nationwide GHG emissions and fossil fuel use. The output of the GREET model can be used directly to calculate tons of GHG and gallons of petroleum reduced. However, these results are not entirely consistent with transportation sector and nationwide emissions inventories which are based on slightly different assumptions concerning fuel heating values and carbon content. As a result we could not use GREET directly to estimate the nationwide impacts of replacing some gasoline and diesel with renewable fuels.

To be consistent between our modeling of savings and overall sector inventories, we used GREET instead to generate comparisons between renewable fuels and the petroleum-based fuels that they displace. These comparisons allowed us to develop displacement indexes which represent the percent of lifecycle GHGs or fossil fuel reduced when a Btu of renewable fuel replaces a Btu of gasoline or diesel. In this way GREET was used to generate percent reductions and not absolute values. These percent reductions or displacement values were then applied to the same gasoline and diesel fuel inventories used to generate transportation sector and nationwide inventories. This ensured that savings and sector wide inventories in terms of absolute values were calculated in a consistent manner.

In order to estimate the impacts of increased use of renewable fuels on fossil energy and greenhouse gases, we first determined how much gasoline and diesel would be replaced as a result of this rule. We then combined lifecycle percent reductions from GREET with lifecycle inventories and petroleum consumption values for gasoline and diesel fuel use to get the amounts of fossil energy and greenhouse gases reduced. For example, to estimate the impact of corn-ethanol use on GHGs, these factors were combined in the following way:

$$S_{GHG,\text{corn ethanol}} = R_{\text{corn ethanol}} \text{ x } LC_{gasoline} \text{ x } DI_{GHG,\text{corn ethanol}}$$

where:

$S_{GHG,\text{corn ethanol}}$ = Lifecycle GHG emission reduction over the reference case associated with use of corn ethanol (million metric tons of GHG)

$R_{\text{corn ethanol}}$ = Amount of gasoline replaced by corn ethanol on an energy basis (Btu)

$LC_{gasoline}$ = Lifecycle emissions associated with gasoline use (million metric tons of GHG per Btu of gasoline)

$DI_{GHG,corn\ ethanol}$ = Displacement Index for GHGs and corn ethanol, representing the percent reduction in gasoline lifecycle GHG emissions which occurs when a Btu of gasoline is replaced by a Btu of corn ethanol

Variations of the above equation were also generated for impacts on all four endpoints of interest (fossil fuel consumption, petroleum consumption emissions of CO_2, and emissions of GHGs) as well as all three renewable fuels examined (corn-ethanol, cellulosic ethanol, and biodiesel). These values are then compared to the total U.S. transportation sector and nationwide inventories of fossil energy and greenhouse gases to get the overall impacts of the rule.

In this regard, the impact on overall transportation sector GHG emissions due to the increased use of renewable fuels can be described mathematically as follows:

$$TSector_{\%,GHG} = \frac{S_{GHG,corn\ ethanol} + S_{GHG,cell\ ethanol} + S_{GHG,biodiesel}}{TSector_{GHG}}$$

where:

$TSector_{\%,GHG}$ = Percent reduction in overall transportation sector GHG emissions resulting from the use of renewable fuels (%)

$S_{GHG,corn\ ethanol}$ = Lifecycle GHG emission reduction over the reference case associated with use of corn ethanol (million metric tons of GHG)

$S_{GHG,cell\ ethanol}$ = Lifecycle GHG emission reduction over the reference case associated with use of cellulosic ethanol (million metric tons of GHG)

$S_{GHG,biodiesel}$ = Lifecycle GHG emission reduction over the reference case associated with use of biodiesel (million metric tons of GHG)

$TSector_{GHG}$ = Overall transportation sector GHG emissions in 2012 (million metric tons of GHG)

We used the same approach to estimate fossil energy, petroleum energy, and CO_2 reductions in the transportation sector. We also used the same approach to estimate nationwide reductions.

Section 6.2.1 describes how we estimated the amount of gasoline and diesel fuel replaced as modeled for this rule. Section 6.2.2 describes the lifecycle emissions and energy associated with gasoline and diesel fuel use. In Section 6.2.3 below, we outline how we generated displacement indexes using GREET. Section 6.2.4 outlines how we developed the overall transportation sector and nationwide fossil energy and greenhouse gas emissions.

6.2.1 Modeling Scenarios

In general, the volume fraction (R) in the equation above represents the amount of conventional fuel no longer consumed – that is, displaced – as a result of the use of the replacement renewable fuel. Thus R represents the incremental amount of renewable fuel used under each of our renewable fuel volume scenarios, in units of Btu. We make the assumption that vehicle energy efficiency will not be affected by the presence of renewable fuels (i.e., efficiency of combusting one Btu of ethanol is equal to the efficiency of combusting one Btu of gasoline).

As described in Section 6.1.1.4, our analysis of the GHG and fossil fuel consumption impacts of renewable fuel use was conducted using three volume scenarios. The total volumes for all three scenarios are shown in Table 6.1-3. For the purposes of calculating the R values, we assumed the ethanol volumes shown in Table 6.1-3 are 5% denatured, and the ethanol volumes were adjusted down to represent pure (100%) ethanol. The adjusted volumes were then converted to total Btu using the appropriate volumetric energy content values (76,000 Btu/gal for ethanol, and 118,000 Btu/gal for biodiesel).

Since the impacts of increased renewable fuel use were measured relative to the 2012 reference case, the value of R actually represented the incremental amount of renewable fuel between the reference case and each of the two other scenarios. The results are shown in Table 6.2-1. The results shown in Table 6.2-1 are direct reductions in fuel use and do not represent lifecycle savings.

Table 6.2-1.
Direct Conventional Fuel Replaced in 2012 (quadrillion Btu)

	RFS Case	**EIA Case**
Gasoline Replaced by Corn Ethanol	0.147	0.347
Gasoline Replaced by Cellulosic Ethanol	0.018	0.018
Diesel Fuel Replaced by Biodiesel	0.032	0.032
Gasoline Replaced by Ethanol Imports	0.031	0.045
Total Energy	0.229	0.443

6.2.2 Lifecycle Impacts of Conventional Fuel Use

In order to determine the lifecycle impact that increased renewable fuel volumes may have on any particular endpoint (fossil fuel consumption or emissions of GHGs), we also needed to know the conventional fuel inventory on a lifecycle basis. Since available sources of GHG emissions are provided on a direct rather than a lifecycle basis, we converted these direct emission and energy estimates into their lifecycle counterparts.

To do this, we used GREET to develop multiplicative factors for converting direct (vehicle-based) emissions of GHGs, or direct (vehicle-based) consumption of petroleum, into full lifecycle factors. GREET output was used to generate the conversion factors shown in Table 6.2-2.

Table 6.2-2.
Direct (wheel only) Conversion Factors to Well-to-Wheel (lifecycle) Emissions or Energy Use

	Gasoline	Diesel
Petroleum	1.11	1.10
Fossil fuel	1.22	1.21
GHG	1.26	1.25
CO_2	1.23	1.21

The factors in Table 6.2-2 were applied to gasoline and diesel fuel inventories of emissions or energy consumption at the consumer level (i.e. direct emissions or energy) to convert them into alternative inventories representing full lifecycle contributions.

The direct petroleum energy for gasoline and diesel fuel is just the energy content of the fuels used. Consistent with U.S. EPA National Inventory calculations[16], we converted energy use values for gasoline and diesel fuel to direct CO_2 emissions by multiplying by a carbon content coefficient, a carbon oxidation factor, and converting the resulting carbon emissions into CO_2. The CO_2 emissions were then scaled up by assuming a fraction increase to the CO_2 emissions to account for non-CO_2 GHGs (CH_4 and N_2O). The fraction increase was based on the U.S. EPA National Inventory 2004 values for both CO_2 and total GHG emissions. Table 6.2-3 shows the total lifecycle petroleum and GHG emissions associated with direct use of a Btu value of gasoline or diesel fuel. These values represent factor LC in the equation described above.

Table 6.2-3.
Lifecycle Emissions and Energy (LC Values)

	Gasoline	Diesel
Petroleum (Btu/Btu)	1.11	1.10
Fossil fuel (Btu/Btu)	1.22	1.21
GHG (Tg-CO_2-eq/QBtu)	99.4	94.5
CO_2 (Tg-CO_2/QBtu)	94.2	91.9

6.2.3 Displacement Indexes

In order to permit a quantitative evaluation of the degree to which a renewable fuel reduces lifecycle fossil fuel consumption or GHG emissions, several metrics have been developed. Three of the most prominent metrics are shown in Table 6.2-4.

Table 6.2-4. Metrics Used to Measure Lifecycle Impacts of Renewable Fuels

Metric	**Calculation**
Net energy balance	Renewable energy out - fossil energy in
Energy efficiency	Fossil energy in ÷ renewable energy out (or alternatively renewable energy out ÷ fossil energy in)
Displacement index	% reduction in emissions or energy compared to the fuel that it replaces

Of these metrics, we believe the displacement index is the most appropriate to use as it compares the renewable fuel to the petroleum fuel it is displacing. The net energy balance and energy efficiency approaches only consider the renewable fuel itself and do not account for the fact that the use of renewable fuels result in decreased use of petroleum fuels and thus provide misleading results.

As an example, if 81,000 Btu of fossil fuels were required to make, transport, and store one gallon of ethanol, then the energy efficiency would be calculated as follows:

$$\text{Energy efficiency} = 81{,}000 \text{ Btu/gal} \div 76{,}000 \text{ Btu/gal} = 1.07$$

This result would imply that ethanol cannot be labeled "renewable," since one gallon of ethanol contains less energy than was required to make that one gallon. However, the use of ethanol may still reduce overall lifecycle fossil fuel use even in this case. If, for example, 18,000 Btu of fossil fuels were required to make one ethanol-equivalent gallon of gasoline (i.e. 76,000 Btu of gasoline), then a total of 94,000 Btu of fossil fuel energy would be consumed whenever 76,000 Btu of gasoline energy was combusted in a conventional vehicle. Since 81,000 Btu is less than 94,000 Btu, the use of ethanol would result in less fossil fuel consumption than the use of gasoline, even though the energy efficiency is greater than 1.0. The 81,000 Btu of fossil energy required to produce the ethanol includes lifecycle energy. The energy content of the ethanol (76,000 Btu) itself is not considered fossil energy and therefore not included in the comparison with gasoline calculation above. Thus, even in cases where the net energy balance of a renewable fuel is negative or has energy efficiency less than 1.0[N], there may still be an overall reduction in lifecycle fossil fuel use (and associated GHG emissions) due to decreased petroleum fuel use.

[N] A net energy balance of zero, or an energy efficiency of 1.0, would indicate that the full lifecycle fossil fuels used in the production and transportation of ethanol are exactly equal to the energy in the ethanol itself.

Therefore, studies that rely on the energy balance metric and conclude for example that the net energy balance of corn ethanol is negative, or the energy efficiency is less than 1.0, making it an unattractive transportation fuel, are not capturing the full implications of the use of the fuel and are providing misleading results.

Because of this potential for the net energy balance and energy efficiency metrics to provide misleading information, for our analysis of this rule we have chosen to use the displacement index. The displacement index provides the most direct measure of the impacts of replacing conventional gasoline or diesel with a renewable fuel, and is also better suited to describing impacts of renewable fuel use on fossil fuel consumption and GHGs.

The displacement index (DI) represents the percent reduction in GHG emissions or fossil fuel energy brought about by the use of a renewable fuel in comparison to the conventional gasoline or diesel that the renewable fuel replaces. The formula for calculating the displacement index depends on which fuel is being displaced (i.e. gasoline or diesel), and which endpoint is of interest (e.g. petroleum energy, GHG). For instance, when investigating the CO_2 impacts of ethanol used in gasoline, the displacement index is calculated as follows:

$$DI_{CO2} = 1 - \frac{\text{lifecycle } CO_2 \text{ emitted for ethanol in g/Btu}}{\text{lifecycle } CO_2 \text{ emitted for gasoline in g/Btu}}$$

The units of g/Btu ensure that the comparison between the renewable fuel and the conventional fuel is made on a common basis, and that differences in the volumetric energy content of the fuels is taken into account. The denominator includes the CO_2 emitted through combustion of the gasoline itself in addition to all the CO_2 emitted during its manufacturer and distribution. The numerator, in contrast, includes only the CO_2 emitted during the manufacturer and distribution of ethanol, not the CO_2 emitted during combustion of the ethanol.

The combustion of biomass-based fuels, such as ethanol from corn and woody crops, generates CO_2. However, in the long run the CO_2 emitted from biomass-based fuels combustion does not increase atmospheric CO_2 concentrations, assuming the biogenic carbon emitted is offset by the uptake of CO_2 resulting from the growth of new biomass[17]. As a result, CO_2 emissions from biomass-based fuels combustion are not included in their lifecycle emissions results and are not used in the CO_2 displacement index calculations shown above. Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or crop lands are accounted for separately in the GREET model.

When calculating the GHG displacement index, however, the CH_4 and N_2O emitted during biomass-based fuels combustion are included in the numerator. Unlike CO_2 emissions, the combustion of biomass-based fuels does result in net additions of CH_4 and N_2O to the atmosphere. We assume that combustion CH_4 and N_2O emissions are not offset by carbon uptake of renewable biomass production. As shown in Table 6.1-2, CH_4 and N_2O emissions contribute to the total GHG impact. Therefore, combustion CH_4 and N_2O emissions are included in the lifecycle GHG emissions results for biomass-based fuels and are used in the GHG displacement index calculations.

Using GREET, we calculated the lifecycle values for energy consumed and GHGs produced for corn-ethanol, cellulosic ethanol, and soybean-based biodiesel, as well as the gasoline and diesel fuel that would be displaced. For both renewable and conventional fuels, we summed the lifecycle results for both the feedstock and the fuel. The results are shown in Table 6.2-5.

Table 6.2-5. Output from GREET Used to Develop Displacement Indexes

	Units	Gasoline[a]	Corn ethanol	Corn ethanol (biomass fuel)	Cellulosic ethanol	L S Diesel	Biodiesel
Well-to-Pump							
Fossil energy	Btu/mmBtu	224,133	742,411	290,324	88,973	207,008	464,594
Petroleum energy	Btu/mmBtu	107,298	90,771	88,896	91,977	98,656	96,539
CO_2	g/mmBtu	17,893	56,275	26,089	-71	16,629	28,468
CO_2-eq	g/mmBtu	20,435	75,219	43,043	6,427	19,134	31,193
End point combustion							
Fossil energy	Btu/mmBtu	1,000,000	0	0	0	1,000,000	0
Petroleum energy	Btu/mmBtu	1,000,000	0	0	0	1,000,000	0
CO_2 combustion[b]	g/mmBtu	76,419	74,755	74,755	74,755	77,570	79,388
Fossil CO_2 combustio		76,419	0	0	0	77,570	0

n							
CO_2-eq	g/mmBtu						
combustion[c]		79,015	2,596	2,596	2,596	77,669	99

[a] Volume-weighted average of conventional gasoline (65%), RFG blendstock (25%), and CaRFG blendstock (10%).

[b] Based on carbon content of the fuel.

[c] Includes Fossil CO_2, CH_4, and N_2O tailpipe emissions. CH_4 and N_2O emissions based on assuming an increase over CO_2 emissions, the percent increase is from the U.S. EPA National Inventory for CO_2 and GHG emissions from on-road sources.

We used the values from the table above to calculate the displacement indexes. The results are shown in Table 6.2-6.

Table 6.2-6. Displacement Indexes Derived from GREET

	Corn ethanol	Corn ethanol (biomass fuel)	Cellulosic ethanol	Imported ethanol	Biodiesel
$DI_{Fossil\ Fuel}$	39.3%	76.3%	92.7%	69.0%	61.5%
$DI_{Petroleum}$	91.8%	92.0%	91.7%	92.0%	91.2%
DI_{GHG}	21.8%	54.1%	90.9%	56.0%	67.7%
DI_{CO2}	40.3%	72.3%	100.1%	71.0%	69.8%

The displacement indexes in this table represent the impact of replacing a Btu of gasoline or diesel with a Btu of renewable fuel. Thus, for instance, for every Btu of gasoline which is replaced by corn ethanol, the total lifecycle GHG emissions that would have been produced from that Btu of gasoline would be reduced by 21.8 percent. For every Btu of diesel which is replaced by biodiesel, the total lifecycle petroleum energy that would have been consumed as a result of burning that Btu of diesel fuel would be reduced by 91.2 percent.

Consistent with the cost modeling done for this rule, for the 2012 cases we assume the “cellulosic” ethanol volume is actually produced from corn utilizing a biomass fuel source at the ethanol production plant. The displacement index for that fuel as shown in Table 6.2-6, is used in the calculation of reductions.

The displacement index for imported ethanol in all cases is based on an average of corn and cellulosic ethanol. While not exclusively, we anticipate much imported ethanol to be primarily sugarcane based ethanol. There currently is no sugarcane ethanol lifecycle values included in GREET. The GHG emissions when producing sugarcane ethanol differs from corn ethanol in that the GHG emissions from growing sugarcane is likely different than for growing a equivalent amount of corn to make a gallon of ethanol, the process of turning sugar into ethanol is easier and therefore less energy intensive (which typically translates into lower GHG) and, importantly, we understand that at least some of the ethanol produced in Brazil uses the bagasse from the sugarcane itself as a process fuel source. We know from our analysis that using a biomass source for process energy greatly improves the GHG benefit of the renewable fuel. These factors would result in sugarcane ethanol having a greater GHG benefit per gallon than corn ethanol, certainly where natural gas or coal is the typical process fuel source used. Conversely, sugarcane ethanol production does not result in a co-product such as distillers grain as in the case of corn ethanol. In our analyses, accounting for co-products significantly improved the GHG displacement index for corn ethanol. Furthermore, there would be additional transportation emissions associated with transporting the imported ethanol to the U.S. as compared to domestically produced ethanol. Developing a technically rigorous lifecycle estimate for energy needs and GHG impacts for sugarcane ethanol is not a simple task and was not available in the timeframe of this rulemaking. Considering all of the differences between imported and domestic ethanol, for this rulemaking, we assumed imported ethanol would be predominately from sugarcane and have estimated DI's approximately mid-way between the DI's for corn ethanol and DI's for cellulosic ethanol. We are continuing to develop a better understanding of the lifecycle energy and GHG impacts of producing ethanol from sugarcane and other likely feedstocks of imported ethanol for any future analysis.

6.2.4 Transportation Sector and Nationwide Inventories

For our analysis described above, we need estimates of transportation sector and nationwide fossil energy and GHG emissions to determine the percent reduction impacts of the program (e.g., $TSector_{GHG}$ factor in the equation above). These inventories are direct not lifecycle and are needed for 2012 to compare to the projected renewable fuel savings in 2012.

6.2.4.1 Fossil Fuel Inventory

The transportation sector and nationwide fossil fuel inventory is just the energy content of the fuels used. Fossil fuel use in the transportation sector includes gasoline and diesel as well as other petroleum fuels, such as residual oil and LPG. It also includes other fossil energy use in the form of natural gas and the fossil portion of electricity used. Inherent with the assumptions on the amounts of renewable fuels use projected to 2012, there are also assumed values for gasoline and diesel fuel use. Values for energy use of the different transportation fuels other than gasoline and diesel (e.g., jet fuel, natural gas, etc.) were taken directly from the 2006 Annual Energy Outlook.

The nationwide fossil fuel inventory includes petroleum, natural gas, and coal energy use. The direct fossil fuel inventory values are shown in Table 6.2-7.

Table 6.2-7. Direct Fossil Fuel Inventories (QBtu)

	2012
Nationwide	94.53
Transportation Sector	31.41

6.2.4.2 Petroleum Inventory

As with fossil energy, the transportation sector and nationwide petroleum inventory is just the energy content of the fuels used. The transportation sector petroleum inventory includes gasoline and diesel as well as other petroleum fuels, such as residual oil and LPG.

The nationwide petroleum inventory includes petroleum use in the transportation sector as well as other sectors. The direct petroleum inventory values are shown in Table 6.2-8.

Table 6.2-8. Direct Petroleum Inventories (QBtu)

	2012
Nationwide	43.87
Transportation Sector	30.47

6.2.4.3 CO_2 Inventories

We calculated direct CO_2 emissions for the transportation sector in 2012 by applying carbon emissions factors to the projected amount of fuels used in those years.

Direct CO_2 emissions from the transportation sector as a whole are calculated in the same way as direct gasoline and diesel emissions are calculated as described in Section 6.2.2. We converted energy use values for transportation sector fuels to direct CO_2 emissions by multiplying by a carbon content coefficient, a carbon oxidation factor, and converting the resulting carbon emissions into CO_2. Emissions from electricity use in the transportation sector (rail) are calculated based on the U.S. average mix of fossil fuels used to generate electricity.

Consistent with the EPA inventory report we made an adjustment to diesel fuel, jet fuel and residual oil use to subtract out the emissions associated with bunker fuel. The AEO values include the energy use of bunker fuels, but the emissions of these fuels are not considered part of the U.S. transportation sector emissions. This adjustment was done by decreasing emissions of diesel fuel, jet fuel, and residual oil by the portion of emissions associated with bunker fuels as determined in the EPA inventory report.

Direct nationwide CO_2 emissions are also calculated in the same way applying factors for all fossil fuels used as reported by the 2006 Annual Energy Outlook. This type of analysis results in a small understatement of total Nationwide CO_2 emissions as it does not capture other industrial sources of CO_2 emissions for example CO_2 emissions from calcinations of limestone in the cement industry. However, there are no projections of these other emissions sources for 2012, and they are a relatively small part of total Nationwide CO_2 emissions, representing only 6% of total CO_2 emissions in 2004 according to the EPA National Inventory values. Therefore, while impacts of increased renewable fuel use as a percent of nationwide CO_2 emissions may be slightly overestimated the impacts on results are not thought to be significant. The results of direct CO_2 emission calculations are shown in Table 6.2-9.

Table 6.2-9. CO_2 Direct Inventories (Tg CO_2)

	2012
Nationwide	6,406
Transportation Sector	2,108

6.2.4.4 GHG Inventories

Projections for direct GHG emissions can not be calculated directly from the energy projections as was done for CO_2. The approach to estimating CO_2 emissions from mobile combustion sources varies significantly from the approach to estimating non-CO_2 GHG emissions (CH_4 and N_2O emissions). While CO_2 can be reasonably estimated by applying an appropriate carbon content and fraction of carbon oxidized factor to the fuel quantity consumed, CH_4 and N_2O emissions depend largely on the emissions control equipment used (e.g., type of catalytic converter) and vehicle miles traveled. Emissions of these gases also vary with the efficiency and vintage of the combustion technology, as well as maintenance and operational practices. Due to this complexity, a much higher level of uncertainty exists in the estimation of CH_4 and N_2O emissions from mobile combustion sources, compared to the estimation of CO_2 emissions.

Projections for direct transportation sector and nationwide GHG emission are done by assuming a fraction increase to the CO_2 emissions to account for non-CO_2 GHGs. The fraction increase was based on the U.S. EPA National Inventory 2004[18] values for both CO_2 and total GHG emissions. This same increase is applied to 2012 CO_2 values. Table 6.2-10 shows the fraction increase values for GHGs over CO_2 emissions calculated from the U.S. EPA National Inventory report.

Table 6.2-10. U.S. National Inventory 2004 CO_2 and GHG Inventories

	CO_2 ($Tg-CO_2$)	GHG ($Tg-CO_2$–eq.)	Fraction Increase
Nationwide	5,988	7,074	1.1807
Transportation Sector	1,860	1,960	1.0538

The results of direct GHG emission calculations are shown in Table 6.2-11.

Table 6.2-11. GHG Direct Inventories (Tg CO_2-eq.)

	2012
Nationwide	7,564
Transportation Sector	2,222

6.3 Impacts of Increased Renewable Fuel Use

We used the methodology described above to estimate impacts of increased use of renewable fuels on consumption of petroleum and fossil fuels and also emissions of CO_2 and GHGs. This section describes our results.

6.3.1 Fossil Fuels and Petroleum

We used the S equation in Section 6.2 to estimate the reduction associated with the increased use of renewable fuels on lifecycle fossil fuel and petroleum consumption. These values are then compared to the total U.S. transportation sector and nationwide inventories to get a percent reduction. The estimates are presented in Tables 6.3-1 and 6.3-2.

Table 6.3-1.
Estimated Fossil Fuel Impacts of Increased Use of Renewable Fuels in 2012, In Comparison to the Reference Case

	RFS Case	**EIA Case**
Reduction (quadrillion Btu)	0.15	0.27
Percent reduction in Transportation Sector Energy Use	0.48 %	0.85 %
Percent reduction in Nationwide Energy Use	0.16 %	0.28 %

Table 6.3-2.
Estimated Petroleum Impacts of Increased Use of Renewable Fuels in 2012, In Comparison to the Reference Case

	RFS Case	**EIA Case**
Reduction (billion gal)	2.0	3.9
Percent reduction in Transportation Sector Energy Use	0.82 %	1.60 %
Percent reduction in Nationwide Energy Use	0.57 %	1.11 %

6.3.2 Greenhouse Gases and Carbon Dioxide

We used the S equation in Section 6.2 to estimate the reduction associated with the increased use of renewable fuels on lifecycle emissions of CO_2. These values are then compared to the total U.S. transportation sector and nationwide emissions to get a percent reduction. The estimates are presented in Table 6.3-3.

Table 6.3-3.
Estimated CO_2 Emission Impacts of Increased Use of Renewable Fuels in 2012, In Comparison to the Reference Case

	RFS Case	**EIA Case**
Reduction (million metric tons CO_2)	11.0	19.5
Percent reduction in Transportation Sector Emissions	0.52 %	0.93 %
Percent reduction in Nationwide Emissions	0.17 %	0.30 %

Carbon dioxide is a subset of GHGs, along with CH_4 and N_2O as discussed above. It can be seen from Table 6.2-6 that the displacement index of CO_2 is greater than for GHGs for each renewable fuel. This indicates that lifecycle emissions of CH_4 and N_2O are higher for renewable fuels that for the conventional fuels replaced. Therefore, reductions associated with the increased use of renewable fuels on lifecycle emissions of GHGs are lower than the values for CO_2. The estimates for GHGs are presented in Table 6.3-4.

Table 6.3-4.
Estimated GHG Emission Impacts of Increased Use of Renewable Fuels in 2012, In Comparison to the Reference Case

	RFS Case	**EIA Case**
Reduction (million metric tons CO_2-eq.)	8.0	13.1
Percent reduction in Transportation Sector Emissions	0.36 %	0.59 %
Percent reduction in Nationwide Emissions	0.11 %	0.17 %

6.4 Implications of Reduced Imports of Petroleum Products

6.4.1 Impacts on Imports of Petroleum Products

To assess the impact of the RFS program on petroleum imports, the fraction of domestic consumption derived from foreign sources was estimated using results from the AEO 2006. We describe in this section how fuel producers might change their levels and mix of imports in response to a decrease in fuel demand.

We compared the levels and mix of imports in the AEO reference case with the AEO low macroeconomic growth case and AEO high oil price case. The latter two cases reflect different assumptions by EIA regarding economic growth and world oil prices, respectively. The net effect for both cases is a reduction in domestic petroleum consumption compared to the AEO reference case. The changes in the level and mix of imports were examined, given a reduction in petroleum consumption similar to the amount estimated in the RFS for 2012 (0.25 to 0.49 Quads). Note that the EIA has conducted three separate analyses of Congressional bills which included earlier forms of the renewable fuel standard. These separate analyses however were based on earlier AEO versions and, in some instances, considered numerous provisions in addition to an RFS which collectively affected world oil prices and domestic oil consumption. Thus, we did not directly use these earlier analyses, rather opting to use only the results in the AEO 2006 cases, as discussed above, to assess the RFS impacts on imports.

Comparison of the AEO 2006 reference case against the low macroeconomic growth case allowed us to evaluate how a decrease in domestic petroleum demand might affect the mix of imported finished products, imported crude oil, and domestic production. Note that the world price of crude oil remains the same between the AEO low macroeconomic growth and reference cases. Comparison of the two cases show that with an initial decrease in petroleum consumption (approximately 300,000 barrels per day or 0.61 Quads, higher than 2012 values), net imports will account for approximately 95% of the reductions on an energy basis.[19] These net imports include imports of crude oil or petroleum products minus exports of crude oil or petroleum products.[20] Both reduced domestic crude production and natural gas plant liquids account for most of the remainder. Note that for all levels of reduced petroleum demand, domestic crude production appears to account for less than 5% of the change. In addition, the reductions shown here do not reflect any rebound effect that may occur. Out of the initial reductions in net petroleum imports, imported finished products account for almost all the reductions. As domestic petroleum demand is reduced even further (over 860,000 barrels per day), approximately 50% of the reductions come from imported finished products, 44% from imported crude oil, and the remainder from reduced domestic, natural gas plant liquid (NGL) production, and exports.

Under the low macroeconomic growth case assumptions, imported finished products are initially reduced presumably because they represent the higher marginal cost source for refineries versus imported crude oil. Refineries may prefer to refine crude oil as opposed to importing finished products because of the higher margins involved with the former and the potentially more optimum use of refining capacity. Crude oil, as an international commodity, will be purchased at the market price by refineries. Thus, while crude oil from abroad may be produced more cheaply than domestic production sources, refineries that purchase from either source will pay the international market price for that specific grade of crude oil based on specific gravity and sulfur content plus the cost of transport to the U.S.

Note that there is uncertainty in quantifying how refineries will change their mix of sources with a decrease in petroleum demand, particularly at the levels estimated for the RFS. Changes in world oil price from the reference case could also significantly alter the mix of sources from which refineries choose. For example, a comparison between the AEO high price case and the reference case (under a decrease in petroleum consumption of 0.64 Quads) shows that 80% of the reductions (on an energy basis) come from reductions in net petroleum imports, while the remaining 20% comes from reductions in domestic production. As petroleum consumption is reduced even further, reductions in net petroleum imports make up an even greater percentage. For the reductions in net petroleum imports, imports of finished products are observed to actually increase while imports of crude oil decrease even more.

We believe that the actual refinery response might range between these two AEO cases, so that net import reductions could compose 80-95% of the reductions in petroleum demand for 2012. The split between the changes in imports of finished products versus crude oil are more uncertain. Discussions with EIA suggest the split could be close to 50-50. Thus, we believe the range could be between these two estimates (nearly all to 50% finished product). For the purposes of this RIA, we show values for the case where net import reductions come entirely from imports of petroleum products, with an example shown below.

By using the petroleum reduction levels as discussed in 6.3.2 of the RIA and comparing these to the AEO 2006 results, we estimate that 95% of the lifecycle petroleum reductions will be met through reductions in net petroleum imports. Table 6.4-1 shows the reductions in net petroleum imports estimated for the RFS program. We expect that these import reductions will be met almost exclusively from finished petroleum products rather than from crude oil, for the reasons given above and consistent with the results of the AEO 2006 low macroeconomic growth case. As an example calculation, we apportioned 95% of the total reductions in gasoline and diesel to displaced finished product imports. By 2012, imports of finished products are estimated to be reduced by 123,000 and 240,000 barrels per day, respectively, for the RFS and EIA cases. We compare these reductions in imports against the AEO projected levels of net petroleum imports. The range of reductions in net petroleum imports are estimated to be between 0.9 to 1.7%.

Table 6.4-1. Net reductions in Imports in 2012

	RFS Case	EIA Case
Reduction in finished products[a] (barrels per day)	123,000	240,000
Percent reduction[b]	0.89%	1.73%

[a] Net reductions relative to 2012 reference case
[b] Compared to AEO2006 projections for 2012 reference case

6.4.2 Impacts on Import Expenditures

The reductions in petroleum imports were discussed in Section IX.D of the preamble. As noted in the preamble, we calculate the change in expenditures on petroleum imports and ethanol imports assuming this would not result in any other changes in consumer behavior that would be reflected in fuel use. 95% of all reductions in petroleum imports were calculated to be from finished petroleum products rather than crude oil, as discussed in the prior section. The economic savings in petroleum product imports was calculated by multiplying the reductions in gasoline and diesel imports by their corresponding price. According to the EIA, the price of imported finished products is the market price minus domestic local transportation from refineries and minus taxes.[21] An estimate was made by using the AEO 2006 wholesale gasoline, distillate, and ethanol price forecasts for the specific analysis years. The current ethanol import tariff of $0.54/gallon placed on countries outside the Caribbean and Central America is not included in the import expenditures, since the tariff revenue collected would remain in the U.S.

As an example calculation, the RFS case is expected to yield a reduction of 2.0 billion gallons of gasoline in the year 2012. 95% of these reductions, or 1.9 billion gallons, are expected to come from imports of finished gasoline. Thus, the domestic refining sector would avoid purchases of 1.9 billion gallons of gasoline and diesel at the wholesale price. According to the AEO 2006, the end-user prices of gasoline and diesel are forecasted to be $2.01 per gallon and $1.98 per gallon respectively. Minus federal taxes, state taxes, and distribution costs, the wholesale prices of gasoline and diesel forecasted in the AEO 2006 are $1.376 and $1.382 per gallon, respectively (2004$). Note that the AEO wholesale prices were used for this calculation, as opposed to the gasoline and diesel production costs in Chapter 7 of the RIA, to stay consistent with the other AEO results used herein. The avoided petroleum payments abroad thus total $2.6 billion in 2012 as shown in Table 6.4-2. The additional ethanol import expenditures, using the same approach, is estimated to be $0.7 billion in 2012. The net avoided expenditures in imports is thus the difference, or $1.9 billion in 2012 as shown in Table 6.4-2.

We compare these avoided petroleum import expenditures against the projected value of total U.S. net exports of all goods and services economy-wide. Net exports is a measure of the difference between the value of exports of goods and services by the U.S. and the value of U.S. imports of goods and services from the rest of the world. For example, according to the AEO 2006, the value of total import expenditures of goods and services exceeds the value of U.S. exports of goods and services to the rest of the world by $695 billion for 2006 (for a net export level of minus $695 billion) and by $383 billion for 2012 (for a net export level of minus $383 billion).[O] In Table 6.4-2, we compare the avoided expenditures in imports versus the total value of U.S. net exports of goods and services for the whole economy for 2012. Note that changes to corn exports, discussed in Chapter 8 of the RIA, are also included in the calculation of net exports. Relative to the 2012 projection, the avoided import expenditures due to the RFS would represent 0.4 to 0.7% of economy-wide net exports.

[O] For reference, the U.S. Bureau of Economic Analysis (BEA) reports that the 2005 import expenditures on energy-related petroleum products totaled $235.5 billion (2004$) while petroleum exports totaled $13.6 billion – for a net of $221.9 billion in expenditures. Net petroleum expenditures made up a significant fraction of the $591.3 billion current account deficit in goods and services for 2005 (2004$). (http://www.bea.gov/)

Table 6.4-2.
Avoided Import Expenditures ($2004 billion)

Cases	AEO Total Net Exports	Expenditures on Petroleum Imports	Expenditures on Ethanol Imports	Decreased Corn Exports	Net Expenditures on Imports	Percent of Total Net Exports
RFS Case	- $383 (year 2012)	- $2.6	+ $0.7	+ $0.6	- $1.4	0.4%
EIA Case		- $5.1	+ $1.0	+ $1.3	- $2.8	0.7%

6.5 Energy Security Implications of RFS

6.5.1 Background

One of the effects of increased use of renewable fuels in the U.S. from the RFS is that it diversifies the energy sources in making transportation fuel. A potential disruption in supply reflected in the price volatility of a particular energy source carries with it both financial as well as strategic risks. These risks can be reduced to the extent that diverse sources of fuel energy reduce the dependence on any one source. This reduction in risks is a measure of improved energy security.

At the time of the proposal, EPA stated that an analysis would be completed and estimates provided in support of this rule. In order to understand the energy security implications of the RFS, EPA has worked with Oak Ridge National Laboratory (ORNL), which has developed approaches for evaluating the social costs and energy security implications of oil use. In a new study produced for the RFS, entitled "*The Energy Security Benefits of Reduced Oil Use, 2006-2015,*" ORNL has updated and applied the method used in the 1997 report "*Oil Imports: An Assessment of Benefits and Costs*", by Leiby, Jones, Curlee and Lee.[P],[Q] While the 1997 report including a description of methodology and results at that time has been used or cited on a number of occasions, this updated analysis and results have not been available for full public consideration. Since energy security will be a key consideration in future actions aimed at reducing our dependence on oil, it is important to assure estimates of energy security impacts have been thoroughly examined in a full and open public forum. Since the updated analysis was only recently available, such a thorough analysis has not been possible. Therefore, EPA has decided to consider this update as a draft report, include it as part of the record of this rulemaking and invite further public analysis and consideration of both this particular draft report but also other perspectives on how to best quantify energy security benefits. To facilitate that

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[P] Leiby, Paul N., Donald W. Jones, T. Randall Curlee, and Russell Lee, *Oil Imports: An Assessment of Benefits and Costs,* ORNL-6851, Oak Ridge National Laboratory, November, 1997.

[Q] The 1997 ORNL paper was cited and its results used in DOT/NHTSA's rules establishing CAFE standards for 2008 through 2011 model year light trucks. See DOT/NHTSA, Final Regulatory Impacts Analysis: Corporate Average Fuel Economy and CAFE Reform MY 2008-2011, March 2006.

additional consideration, we highlight below some of the key aspects of this particular draft analysis.

The approach developed by ORNL estimates the incremental benefits to society, in dollars per barrel, of reducing U.S. oil imports, called "oil premium." Since the 1997 publication of this report, changes in oil market conditions, both current and projected, suggest that the magnitude of the oil premium has changed. Significant driving factors that have been revised include: oil prices, current and anticipated levels of OPEC production, U.S. import levels, the estimated responsiveness of regional oil supplies and demands to price, and the likelihood of oil supply disruptions. For this analysis, oil prices from the EIA's AEO 2006 were used. Using the "oil premium" approach, estimates of benefits of improved energy security from reduced U.S. oil imports from increased use of renewable fuels are calculated.

In conducting this analysis, ORNL considered the full economic cost of importing petroleum into the U.S. The full economic cost of importing petroleum into the U.S. is defined for this analysis to include two components in addition to the purchase price of petroleum itself. These are: (1) the higher costs for oil imports resulting from the effect of U.S. import demand on the world oil price and OPEC market power (i.e., the so called "demand" or "monoposony" costs); and (2) the risk of reductions in U.S. economic output and disruption of the U.S. economy caused by sudden disruptions in the supply of imported oil to the U.S. (i.e., macroeconomic disruption/adjustment costs).

1. <u>Effect of Oil Use on Long-Run Oil Price, U.S. Import Costs, and Economic Output</u>

The first component of the full economic costs of importing petroleum into the U.S. follows from the effect of U.S. import demand on the world oil price over the long-run. Because the U.S. is a sufficiently large purchaser of foreign oil supplies, its purchases can affect the world oil price. This monopsony power means that increases in U.S. petroleum demand can cause the world price of crude oil to rise, and conversely, that reduced U.S. petroleum demand can reduce the world price of crude oil. Thus, one consequence of decreasing U.S. oil purchases due to increased use of renewable fuel is the potential decrease in the crude oil price paid for all crude oil purchased.

2. <u>Short-Run Disruption Premium From Expected Costs of Sudden Supply Disruptions</u>

The second component of the external economic costs resulting from U.S. oil imports arises from the vulnerability of the U.S. economy to oil shocks. The cost of shocks depends on their likelihood, size, and length, the capabilities of the market and U.S. Strategic Petroleum Reserve (SPR), the largest stockpile of government-owned emergency crude oil in the world, to respond, and the sensitivity of the U.S. economy to sudden price increases. While the total vulnerability of the U.S. economy to oil price shocks depends on the levels of both U.S. petroleum consumption and imports, variation in import levels or demand flexibility can affect the magnitude of potential increases in oil price due to supply disruptions. Disruptions are uncertain events, so the costs of alternative possible disruptions are weighted by disruption probabilities. The probabilities used by the ORNL study are based on a 2005 Energy Modeling Forum[R] synthesis of expert judgment and are used to determine an expected value of disruption costs, and the change in those expected costs given reduced U.S. oil imports.

3. Costs of Existing U.S. Energy Security Policies

The last often-identified component of the full economic costs of U.S. oil imports is the costs to the U.S. taxpayers of existing U.S. energy security policies. The two primary examples are maintaining a military presence to help secure stable oil supply from potentially vulnerable regions of the world and maintaining the SPR to provide buffer supplies and help protect the U.S. economy from the consequences of global oil supply disruptions.

U.S. military costs are excluded from the analysis performed by ORNL because their attribution to particular missions or activities is difficult. Most military forces serve a broad range of security and foreign policy objectives. Attempts to attribute some share of U.S. military costs to oil imports are further challenged by the need to estimate how those costs might vary with incremental variations in U.S. oil imports. Similarly, while the costs for building and maintaining the SPR are more clearly related to U.S. oil use and imports, historically these costs have not varied in response to changes in U.S. oil import levels. Thus, while SPR is factored into the ORNL analysis, the cost of maintaining the SPR is excluded.

As stated earlier, we have placed the draft report in the docket of this rulemaking for the purposes of inviting further consideration. However, the draft results of that report have not been used in quantifying the impacts of this rule.

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[3] Wang, Saricks, and Wu, 1997, *Fuel-Cycle Fossil Energy Use and Greenhouse Gas Emissions of Fuel Ethanol Produced from U.S. Midwest Corn*, pp. 13; cited in ANL/ESD-38, pp. 65.
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[16] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2004, EPA 430-R-06-002, April 2006.
[17] *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2004,* EPA 430-R-06-002, April 2006.
[18] *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2004,* EPA 430-R-06-002, April 2006.
[19] Net imports of petroleum include imports of crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components minus exports of the same.
[20] Petroleum products, according to the Annual Energy Outlook 2006, includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.

[21] EIA (September 1997), "Petroleum 1996: Issues and Trends", Office of Oil and Gas, DOE/EIA-0615, p. 71. (http://tonto.eia.doe.gov/FTPROOT/petroleum/061596.pdf).